DIRECT TESTIMONY OF

JAMES M. LANDRETH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2002-223-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY (SCE&G or "the Company").

A. James M. Landreth, 111 Research Drive, Columbia, South Carolina. I am employed by South Carolina Electric & Gas Company as Vice President of Fossil and Hydro Generation.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS EXPERIENCE.

A. I have a Bachelor of Science Degree in Textile Technology from North Carolina State University in Raleigh, North Carolina and a MBA Degree from James Madison University in Harrisonburg, Virginia. South Carolina Electric & Gas Company employed me in February, 2000 as Manager of New Business Development for Fossil and Hydro Operations. In May of 2001, I assumed the position as Vice President of Fossil and Hydro Operations. In this position, I report directly to the President of South Carolina Electric & Gas Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a summary of major operational developments of the Company since SCE&G's last rate case in 1995 and explain to the Commission the capital costs of these projects, which the Company now proposes to include in its rate base. Some of these construction projects are linked directly to the Company's growing customer load and the corresponding need to maintain system reliability. In this respect, I will briefly discuss SCE&G's growth in peak demand, its reserve margin, and its projected capacity needs. Also within this context, I will describe the Urquhart Re-Powering Project and the Jasper County Generating Plant.

Other construction projects stem from required refurbishments or improvements to existing plant facilities that are mandated as a result of regulatory directives from the Federal Energy Regulatory Commission (FERC) or because of federal legislative action. Although not included in this docket, the Saluda Dam remediation project is one example of federally mandated construction, and I will briefly describe it and report on its present status. I will also discuss the construction of selective catalytic reduction (SCR) systems and bag houses at several generating units of the Company's coal-fired power production stations.

In addition, I will address SCE&G's operational benchmarks in terms of its forced outage rate, heat rate, and capacity factor to underscore the Company's continuing efficiency of operations and commitment to system reliability as it provides electric service to its native load customers in South Carolina. SCE&G remains dedicated to operating effectively within the parameters of a fully regulated business environment under this Commission's authority. By focusing on performing the Company's electric operations within our home state, we have also helped avoid the pitfalls and instabilities associated with deregulation that have recently plagued the nation's electrical industry.

Q. PLEASE DISCUSS THE COMPANY'S RECENT GROWTH IN PEAK DEMAND.

A. The Company experiences its annual peak demand during the summer. Historical growth in numbers of customers in our service territory and their electricity consumption has resulted in a peak demand growth of about 2.4% per year. For example, during the period 1990 through 2001, our peak demand has increased from 3,222 MW to 4,193 MW or about 88 MW per year. To project future growth in our service territory we use economic and statistical techniques that have become standard in the utility industry. We use econometric models to correlate customer growth and energy consumption with weather, population growth, income growth, employment growth and industrial production. Based on these models and studies, we expect our peak demand to continue to grow about 88 MW per year for the foreseeable future.

Q. DISCUSS THE COMPANY'S RESERVE MARGIN AND PROJECTED CAPACITY NEEDS?

A. At present the Company believes that the prudent level at which to set the reserve margin for capacity is in the range of 12% to 18%. This level should be sufficient to meet our firm load obligations and our daily operating reserve requirements under the VACAR Operating Agreement as well as to cover most supply-related contingencies such as mechanical trouble at one of our plants and demand-related contingencies such as those associated with abnormally hot weather. Based on this reserve margin range, the projected growth in peak demand, and our supply capability of 4,584 MW in the spring of 2002, our forecasted capacity need for the summer peak of 2002 was in the range of 236 to 495 MW. The Urquhart Re-Powering Project added 341 MW to our system capability as of June 1, which met this capacity need for 2002. By 2004 the range in capacity deficit falls between 482 and 772 MW even with the new Urquhart capacity that has been added. The Jasper Plant will add 875 MW of capacity. This represents 103 MW, or about one year of demand growth, above the upper end of our range. It was necessary to go a little above the range (as is typical after adding a large plant to any power production system) in order to capture the economies of scale related to the larger plant configuration. The capacity needs for 2002 and 2004 discussed above take into account 240 MW of demand-side management, most of which is related to interruptible load.

Q. DESCRIBE THE URQUHART RE-POWERING PROJECT.

A. SCE&G has completed installation of two new combustion turbine-generators at our Urquhart Station in Beech Island, Aiken County. These turbine-generators are rated at approximately 150 MW each. Two of the existing Urquhart steam turbine-generators, with a capacity of approximately 75 MW each, are now re-powered by steam produced in two new heat recovery steam generators using the exhaust energy from the two new combustion turbines. An inlet chiller for the combustion turbines has been installed to provide an additional 41 MW capacity during the summer peaking months. The total combined-cycle capacity for these units is approximately 491 MW.

Energy from the new heat recovery steam generator is also being used to provide feedwater heating for the existing Urquhart Unit #3. This feedwater heating capability does not increase the generation capacity for Unit #3 which is approximately 100MW, but it does increase the generation efficiency. Unit #3's coal-fired boiler continues to operate, but the existing coal-fired boilers for Units 1 & 2 have been shut down. The combined-cycle units are capable of firing natural gas or run for a limited period of time on distillate (No. 2) fuel oil, with natural gas being the primary fuel.

Also located at the Urquhart site are four simple cycle combustion turbines (CT 4, 5, 6 and 7) capable of firing natural gas and distillate (No. 2) fuel oil, with natural gas being the primary fuel. The fuel oil for these four combustion turbines continue to be stored in an existing fuel oil tank.

The Urquhart Re-Powering Project is complete, and the re-configured plant began commercial operations on June 1, 2002.

Q. WHAT IS THE TOTAL COST OF THE URQUHART RE-POWERING PROJECT?

A. The total cost of the plant is approximately $248 million. This amount includes the engineering, procurement, and construction (EPC) contract price with Duke/Fluor Daniel (D/FD) as well as the project management costs. In addition, the project required construction of a substation and two new 230 kV transmission lines originating at the Urquhart Station and connecting to the existing grid at Urquhart Junction. The distance of these new transmission lines is approximately 6.3 miles.

The total cost of these associated transmission lines and substation is just over $5 million.

Q. PLEASE DESCRIBE THE JASPER COUNTY GENERATION PROJECT THAT SCE&G PLANS TO BUILD.

A. SCE&G plans to build a combined cycle generating plant on a rural site near Hardeeville in Jasper County, South Carolina. The plant will be composed of three combustion turbine-generators, three heat recovery steam generators (HRSG) and one steam turbine-generator. The HRSGs transfer the heat in the exhaust from the combustion turbines to heat water in the power cycle to produce steam, which then powers the steam turbine to generate additional electricity. The combustion turbines will be equipped with inlet chilling to maximize the output of the plant during hot weather. The plant will generate approximately 775 net megawatts during the winter and 750 net megawatts during the summer. The plant will have the capability to generate additional "peaking" output of up to 120 MW using supplementary firing. This is accomplished by burning additional fuel in burners located in the inlet duct to the HRSGs, which produces more steam and more output from the steam turbine-generator. The peak output from the plant will be approximately 900 MW during the winter and 875 MW during the summer.

Q. WHAT TYPE OF FUEL WILL BE USED BY THE NEW PLANT?

A. Natural gas will be the primary fuel for the plant with distillate (No. 2) fuel oil as a back-up. High pressure natural gas will be supplied to the site through a connection to interstate pipelines. The interstate pipelines will deliver natural gas from both the Gulf of Mexico region and from the liquefied natural gas (LNG) facility near

Savannah, Georgia. Distillate fuel will be delivered to the site from local terminals in truck tankers and stored on the plant site in above-ground storage tanks.

Q. WHAT ENVIRONMENTAL CONTROLS WILL BE INCLUDED IN THE JASPER PLANT?

A. The plant will use dry low NOx combustors when burning natural gas and water injection for NOx control when burning distillate oil. In addition, the HRSGs will include selective catalytic reduction (SCR) systems for further reduction of NOx emissions. Low sulfur distillate oil will be used to minimize oxide of sulfur emissions when burning oil. A closed cycle cooling system with evaporative cooling towers will be used to transfer heat from the steam turbine condensers to the atmosphere. Water "blowdown" from the cooling towers and steam cycle will be returned to the water treating facility for recycling reducing the volume of wastewater generated. The small amount of wastewater generated by the facility will be delivered to the Hardeville wastewater collection and treatment system for processing.

Q. WHAT ARRANGEMENTS HAS SCE&G MADE FOR THE CONSTRUCTION OF THE JASPER PROJECT?

A. SCE&G negotiated a fixed price contract for the engineering, procurement and construction (EPC) of the project with Duke/Fluor Daniel (D/FD). The EPC contract includes schedule and performance guarantees with associated liquidated damage payments if the guarantees are not met for causes solely attributable to D/FD. D/FD will pay penalties for each day substantial completion of the project is delayed beyond May 1, 2004, for each kilowatt the facility fails to meet the net capacity guarantee, and for each Btu/kWh the facility performance is in excess of the net heat rate guarantee. Each of these penalties is limited to 10% of the contract price with an aggregate limit of 15%.

Similar contracts were negotiated for our Urquhart Re-Powering Project and our Cope Station. In both of those cases, the EPC arrangements with D/FD were very successful from the Company's perspective in that both Urquhart and Cope were built under budget and before completion deadlines. Construction at Jasper began in the spring of 2002 with commercial operation of the plant scheduled for May 1, 2004.

Q. WHAT DOES SCE&G ESTIMATE THE TOTAL COST OF THE JASPER PROJECT TO BE?

A. The total cost of the project including Allowance for Funds Used During Construction (AFUDC) but excluding transmission system improvements will be approximately $478 million. However, only the expenses associated with Construction-Work-in-Progress (CWIP) for the Jasper Project that are projected to be incurred as of December 31, 2002, have been included in our proposed rate base. This amounts to approximately $277 million.

Q. EARLIER YOU REFERENCED THE SALUDA DAM REMEDIATION. ALTHOUGH NOT INCLUDED IN THIS DOCKET, BECAUSE OF THE LEVEL OF PUBLIC INTEREST, WILL YOU UPDATE THE COMMISSION ON THE STATUS OF THIS PROJECT.

A. As the Commission well knows, from the early days of the Company's history the impoundment of the Saluda River that formed Lake Murray provided SCE&G with a source of hydroelectric generating capacity. The Saluda Dam, completed in 1930, is a semi-hydraulic fill structure following typical construction technology popular in the early 1900's. Since the primary purpose for which the dam was originally constructed was hydroelectric generation, the dam is under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Today, the lake is a source of cooling water for the McMeekin Steam Plant, drinking water for Columbia and adjacent communities, and a major recreation and residential community with statewide economic benefits.

Beginning in 1989, the FERC required that a series of geo-technical investigations be undertaken to assess the safety of the existing Saluda Dam, particularly under seismic stress. In this part of South Carolina, seismic design bases for critical facilities are, for all practical purposes, governed by a postulated re-occurrence of the 1886 Charleston Earthquake. The Charleston Earthquake is estimated to have had a magnitude in the range of 7.1 to 7.3 on the Richter scale. This event has been established as the Design Seismic Event (DSE) for assessing the integrity of Saluda dam.

A comprehensive liquefaction analysis and a post-earthquake stability analysis were conducted with the DSE, and showed that under certain assumptions a major portion of the embankment will undergo liquefaction if the DSE occurs. Should Saluda Dam fail, approximately 120,000 people would be in jeopardy, water supplies for Columbia and surrounding communities would be lost, extreme environmental impacts would be realized and countless millions of dollars would be lost in the local economy. Consequently, the FERC ordered a major remediation project for Saluda Dam to be implemented in the 2002 to 2005 time period.

The FERC is requiring SCE&G to undertake major remediation of the existing dam with two primary goals:

- Prevent catastrophic downstream flooding in the event of a DSE related dam failure.
- Allow safe shutdown of the existing facilities and drawdown of Lake Murray in a controlled manner.

After consideration, both technical and financial, the FERC determined that the remediation required construction of a new, supplementary "dry dam" immediately downstream of the existing earth dam. The existing embankment will remain in place and function as the primary impounding barrier for Lake Murray. The dry dam will become a water retention structure if Saluda Dam ever fails. In addition, the remediation plan for Saluda Dam includes the following criteria:

- No excavation into the original sluiced dam. Riprap placed after original dam construction will be removed to facilitate excavation.
- No excavation or construction into the Saluda River as defined by the maximum normal tailwater.
- The crest of the new Berm will be equal to the current minimum crest elevation of the existing Dam.

The dry dam will consist of about 5500 linear feet of rock fill and about 2300 linear feet of roller compacted concrete (RCC). This project is the largest active (year 2002) dam construction project in the United States and the final project will involve the placement of 1.3 million cubic yards of RCC and 3.5 million cubic yards of rock fill. The rock fill material, as well as the aggregates used in the RCC and its mass concrete foundations, will be produced from rock obtained from an on-site borrow area. The RCC will be mixed on-site.

At present we anticipate the project will be completed by mid-2005.

Q. WHAT GENERATING PLANT IMPROVEMENTS HAS SCE&G UNDERTAKEN DUE TO FEDERAL ENVIRONMENT LEGISLATION?

A. Since passage of the Clean Air Act of 1977 and its amendments in 1990, the federal government has prescribed protective guidelines aimed at preventing significant deterioration of air quality with particular concern about nitrous oxides, sulfur dioxide, and particulate matter emissions released from coal-fired power plants. Reduction of nitrous oxides is particularly important so that ambient air quality will meet the standard for ozone established by the Environmental Protection Agency (EPA). Similarly, reduction in sulfur dioxide and particulate matter has a positive effect on the surrounding air quality. Accordingly, SCE&G over the last decade has undertaken major construction projects at its existing and new coal-fired plants to comply with federal regulations that safeguard air quality, given the location of some of the Company's power plants in relation to potential air quality impact on Class I areas as defined by the EPA.

In 1998 SCE&G completed the process of replacing the existing burners at both of the two coal-fired units at the McMeekin Station with low NOx burners to comply with Title IV of the Clean Air Act. The cost of these improvements was approximately $7.2 million. In 1999 low NOx burners were installed at the three units at the Canadys Station, and on its Unit #3 a baghouse was constructed to replace the electrostatic precipitator to improve the collection efficiency for flyash to comply with the opacity limits set under the Clean Air Act. These enhancements cost approximately $32.3 million.

In addition, the Company completed other modifications to the McMeekin Station system that resulted in improved treatment of environmental resources. These changes include re-design of the circulating water system and the ash collection system, and they involved moving reservoirs and ash collection ponds. The total cost of this work at McMeekin was $16.2 million.

In 1998 the Company likewise completed the substitution of low NOx burners for the pre-existing burners on the two units at the Wateree Station. In addition, here SCE&G constructed a carbon burnout unit to reburn flyash to reduce the amount of unburned carbon in flyash, which in turn improves unit efficiency, increases the sale potential for flyash, and significantly reduces the need for flyash storage in ash disposal areas (i.e. ash ponds, landfills, etc.). Construction of two selective catalytic reactors and two baghouses has been completed or is in progress for the two Wateree units to comply with the mandated reduction in NOx emissions during the seasons when ozone standards are jeopardized. All of these enhancements at the Wateree Station total approximately $182.8 million. Of this amount, we have included $93 million in the Company's proposed rate base.

Further, let me also note that SCE&G has installed low NOx burners at Unit #3 of the Urquhart Plant at a cost of approximately $1.2 million.

Thus, since the Company's last rate case in 1995 we have undertaken a host of projects at our production facilities related solely to environmental protection and air quality improvement. The total cost for these efforts between 1995 and the present amount to approximately $240 million.

Q. HAVE THERE BEEN OTHER MAJOR CONSTRUCTION PROJECTS FOR ELECTRIC GENERATION OPERATIONS SINCE THE LAST RATE CASE?

A. Since 1995 the Company has completed several other major construction projects that are part of the on-going maintenance of its electric generation stations. At our Fairfield Pump Storage facility we have completed replacement of four existing turbine runners with new runners due to corrosion, cracks in the wicket gates, and vibration. Replacement of two addition runners is in progress as well. These six new runners are more efficient and will increase the facility's capacity by a total of 22.5 MW. The total cost for these improvements amounts to approximately $11.9 million. Of this amount, the Company has included $9.2 million in our proposed rate base for the four completed runners.

In 1999 SCE&G installed a 50MW internal combustion (IC) turbine generator on-site at the Urquhart Station. This installation was separate and distinct from the Urquhart Re-Powering project and was done to meet system peak demand. The cost of this enhancement was approximately $20 million.

These various construction efforts that reflect major improvements and maintenance on the Company's electric power production system represent a total capital cost of approximately $32 million.

Q. PLEASE SUMMARIZE THE PERFORMANCE OF THE COMPANY'S POWER PRODUCTION UNITS.

A. Overall, SCE&G's power production units have operated efficiently and dependably in the twelve-month period of April 1, 2001 through March 31, 2002. In fact, the Company's power plants have operated better than the North American Electric Reliability Council ("NERC") national 5-year (1996-2000) average for forced outage rates and with reasonable heat rates.

SCE&G experienced a low system forced outage rate of 2.36% during the test year. "Forced outage rate" is the percentage of the total hours that generating units are forced out of service for various reasons, compared with the total hours in service for a period. The NERC national 5-year (1996-2000) average for forced outage rate for a comparable system was 4.56%.

Heat rate is a way to measure thermal efficiency of a power plant fuel cycle. It is the number of BTUs of fuel required to generate one kilowatt-hour of electricity. The Company's heat rate for its system for the test year was 9746 Btu/kWh, which is among the best in the nation. Our Cope Station had the best heat rate in our system at 9430 Btu/kWh.

Finally, during the test year the power production system of SCE&G had a capacity factor of 74.44%. The capacity factor is derived by dividing total actual generation by total possible generation.

Q. DO YOU HAVE ANY OTHER COMMENTS TO ADD TO YOUR TESTIMONY FOR THE COMMISSSION?

A. As my testimony has shown, the numerous construction projects that the Company has carried out since 1995 have been done with an overall concern for meeting customer load and maintaining system reliability, complying with regulatory mandates, and addressing the needs of operational efficiency and maintenance. These various efforts include the Urquhart Re-powering Project and the Jasper Generating Station, a number of plant enhancements related to environmental stewardship, and an array of improvements to our power plants that increase efficiency of operations or reflect on-going maintenance, both of which, in turn, translate into greater generation capacity for SCE&G's power production system.

The aggregate capital cost of these construction projects for a period of over seven years since the Company's last rate case amounts to approximately $998 million. SCE&G's decisions to engage in this major construction activity involving substantial investment reflect a steadfast determination to provide efficient, reliable electric service to its native load customers in South Carolina. In its decision-making the Company recognizes at all times the importance of minimizing cost and maximizing effectiveness with respect to meeting the energy needs of South Carolinians. And SCE&G continues to do this within the appropriate boundaries of a regulated utility environment established and maintained by this Commission. It is within this context that the Company therefore seeks to recover the cost of these major capital projects that we have included in our proposed rate base and respectfully asks the Commission for approval of this cost recovery.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.